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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company Proposing Cost of Service and Rates for Gas Transmission and Storage Services for the Period 2015-2017 (U 39 G).	Application 13-12-012 (Filed December 19, 2013)
And Related Matter.	Investigation 14-06-016

CALPINE CORPORATION'S RESPONSE TO DYNEGY AND NORTHERN CALIFORNIA GENERATION COALITION'S APPLICATION FOR REHEARING OF DECISION 16-06-056

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As authorized by Rule 16.1(d) of the California Public Utilities Commission' s ("Commission") Rules of Practice and Procedure, Calpine Corporation ("Calpine") hereby submits this response to the applications for rehearing filed by Dynegy, Inc. ("Dynegy") and the Northern California Generation Coalition ("NCGC," and collectively with Dynegy, "Applicants") of the Commission' s Decision 16-06-056 ("Decision"). The application for rehearing ("Application") of Dynegy and NCGC is without merit and should be denied

INTRODUCTION

Dynegy and NCGC own and operate several electric generation ("EG") facilities that are connected to Pacific Gas and Electric' s ("PG&E") local transmission ("LT") system. Throughout this proceeding, Dynegy and NCGC have sought modifications to PG&E' s rate structure for electric generators ("EG") in order to shift costs associated with the LT system (including new investments by PG&E in the safety of its LT system) to EGs that are connected directly to PG&E's backbone ("BB") system, even though such BB-connected facilities have never used PG&E's LT system, and instead have paid to construct, operate and maintain their own lateral pipeline connections to the BB system. In arguing for this subsidy, Applicants have consistently oversimplified the natural gas and wholesale electricity markets, and have asked the Commission to blindly focus on one cost-factor for electric generators—the cost of LT gas transport—to the exclusion of the myriad other factors that affect the competitiveness of EGs in the complicated California electricity markets. In the Decision, the Commission rightly rejected NCGC's and Dynegy's proposal as unfair and anticompetitive.

Dynegy and NCGC's Application is a transparent effort to re-litigate these requests for subsidies. Applicants' narrow focus on the percentage increase in LT transport rates for LT-connected EG customers approved in the Decision is another attempt to over-simplify the issues. As discussed more fully below, the Commission heard these same complaints throughout this proceeding, and, on the basis of substantial record evidence, declined to subsidize Applicants' commercial operations. Each of Applicants' arguments fail, and their Application should be denied.

Specifically, Applicants argue that the Commission did not find that the rates approved in the Decision are just and reasonable. However, as explained more fully below, the Decision expressly found that the approved revenue requirement and rate structures were just and reasonable, and recognized that the approved rates are determined directly by these elements. Applicants do not dispute this. The Commission also considered the parties' arguments regarding rate impacts to customers, chose to mitigate rate impacts through several mechanisms, and in light of PG&E's need to fund important new safety programs, ultimately concluded that further mitigation was not warranted. The Commission's discussion of rate mitigation clearly evidences that it considered the approved rates, and deemed them just and reasonable. Applicants argue that the Commission's characterization of the rates as "interim" understates the rate increases, and that this somehow goes to show that the Commission did not make adequate findings on the reasonableness of the approved rates. This argument is entirely specious: the Decision did not rely on the fact that the approved rates are "interim" in judging them to be just and reasonable.

Applicants' "rate shock" arguments likewise fail. As indicated above, the Decision balances PG&E's need for large revenue increases to fund safety investments against the rate impacts that will be experienced by customers, and chose a particular level of rate mitigation deemed by the Commission to be appropriate under the circumstances. This policy decision is well within the Commission's broad discretion in rate-setting proceedings. The prior Commission decisions cited by Applicants do not indicate otherwise. In fact, each of the decisions cited by Applicants concern increases in the *total* cost of electricity service to customers, and so differ from the instant Application, which is concerned only with the cost of LT transportation service, a component of the total cost of gas. Further, each decision cited by Applicants is also concerned either with the impact of rate increases on residential customers (which as a class are less able to absorb rate increases than are electric generators), or rate increases due to changes in rate-setting methodologies (which are substantially different than the rate increase in this proceeding, driven by need for safety investments), and so each decision cited by Applicants is not applicable here.

While Applicants provide a laundry-list of measures they contend could have been used to mitigate the rates further, the Commission need not adopt these measures in light of its judgment that the adopted rates are just and reasonable. In any event, as explained further below, the Commission did consider several of these mitigation mechanism, adopted some and rejected others.

Applicants argue that the Commission failed to consider or adequately address the impacts of the adopted rates on wholesale electricity markets. However, Applicants are incorrect; the Decision expressly considered testimony from PG&E witness Mr. Hatton on this exact issue, and decided not to further mitigate rate impacts. Neither Dynegy nor NCGC submitted evidence on this issue. Similarly, the Commission considered evidence from several parties on the "multiplier effect," and concluded that this evidence did not warrant further mitigation of rates.

Finally, Applicants argue that the Commission failed to consider or adequately address the impacts of the adopted rate increases on the relative competitiveness of EG customers connected to the local transmission system. This argument fails in the face of the plain language of the Decision, which considered Applicants' competitiveness concerns at length, and chose not to subsidize such LT-connected EG customers at the expense of other customers. Most notably, the Commission considered Dynegy and NCGC's proposals to restructure EG rates to shift costs associated with the local transmission system to backbone-connected EG customers, and rejected the proposal as unfair and an unwarranted deviation from cost-causation principles. In making their arguments based on alleged competitiveness impacts, Applicants again oversimplify the market by failing to mention the many other factors that can impact an electric generator's competitiveness.

In short, Applicants fail to identify any legal error in the Decision warranting rehearing. The Application should be denied.

STANDARD OF REVIEW

As the Commission recently confirmed, "[r]ehearing applications are not a proper vehicle to merely reargue positions taken during a Commission proceeding".[1] Public Utilities Code section 1732 limits applications for rehearing of Commission decisions to specific allegations of legal error. If the Commission denies an application for rehearing, appeal of the underlying Commission action is to the California Court of Appeal, which will determine "whether the Decision is supported by findings, and if so, whether those findings are supported by substantial evidence in light of the whole record."[2]

In assessing whether the Commission's findings are supported by substantial evidence in light of the whole record, a reviewing court "must consider all relevant evidence in the record," and not just the evidence called out by the Commission in its decision.[3] "It is for the agency to weigh the preponderance of conflicting evidence."[4] "Courts may reverse an agency's decision only if, based on the evidence before the

1 D.16-05-053 at 12 (citing D.12-12-040 at 3).
2 Pub. Util. Code § 1757(a)(3) & (4).
3 *Clean Energy Fuels Corp. v. Pub. Util. Comm'n* (2014) 227 Cal. App. 4th 641, 649.
4 *Id.*

agency, "a reasonable person could not reach the conclusion reached by the agency."[5] "[T]he findings of fact by the [Commission] are to be accorded the same weight that is given to jury verdicts and the findings are not open to attack for insufficiency if they are supported by any reasonable construction of the evidence."[6] "When conflicting evidence is presented from which conflicting inferences can be drawn, the [Commission' s] findings are final."[7] Further, "[i]t is within the [Commission' s] discretion to determine what factors are material to its decision based on the issues before it."[8] DISCUSSION

1. The Revenue Requirements, Rate Structure, and Rates Approved by the Decision are Adequately Supported by Findings and Evidence

a. The Approved Rates Directly Result From PG&E's Revenue Requirement and Rate Structure, which the Commission Considered at Length and Expressly Found to be Just and Reasonable

Applicants seem to acknowledge—as they must—that the Commission made full and adequate findings as to the reasonableness of the adopted revenue requirement and rate structures for Pacific Gas and Electric Company' s ("PG&E' s") gas transportation and storage services. Nevertheless, they argue that the Decision lacks findings as to the reasonableness of the rates themselves.[9] Applicants attempt to draw a distinction without a difference.

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5 *Id.,* citing *SFPP, L.P. v. Pub. Util. Comm'n* (2013) 217 Cal. App. 4th 784, 794.

6 *Id.*

7 *Clean Energy Fuels Corp.* (2014) 227 Cal. App. 4th at 649-650 (citing *Toward Utility Rate Normalization v. Pub. Util. Comm'n* (1978) 22 Cal. 3d 529, 537–538).

8 *Id.* at 659.

9 Application at 7.

As the Decision expressly states, the rates approved by the Decision flow directly from the adopted revenue requirement and rate structures.[10] The Commission painstakingly reviewed these elements, as evidenced, for example, by the more than two hundred pages of the Decision devoted to a review of the various components of PG&E's revenue requirement, clearly considering along the way the impact of its revenue requirement determinations on the resulting rates.[11]

The Commission's many findings and conclusions as to the reasonableness of each component of PG&E's revenue requirement are too numerous to warrant comprehensive discussion here; it is sufficient to note that the Commission conducted a review of each separate component of PG&E's revenue requirement proposal, and that Applicants do not challenge the Commission's substantive findings on the reasonableness of any particular revenue component.

The Commission also devoted more than fifty pages of its Decision to rate design issues.[12] Indeed, a full eighteen pages are focused on discussing, and ultimately rejecting, Dynegy and NCGC's proposals for restructuring electric generation rates.[13] The Commission's discussion of Dynegy and NCGC's rate design proposals plainly considers the rates that would result for electric generation customers connected to

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10 Decision at 342 ("Interim rates based on the revenue requirements adopted in this decision and amortization of the undercollection of the Gas Transmission and Storage Memorandum Account (GTSMA) over a 36-month period are presented in Appendix J."); *id.* at Ordering Paragraph 4.

11 *See generally* Decision at 32 – 257.

12 Decision at 289 – 342.

13 Decision at 320 – 338.

PG&E's backbone and local transportation systems, and concludes that the existing rate design is just and reasonable.[14]

Applicants cite the standard of review for judicial appeal of Commission decisions, and argue that "[a] reviewing court and the affected parties would be hard pressed to `ascertain the principles relied upon by the commission' or `know why the case was lost' based on the Decision's findings and conclusions."[15] Applicants argue further that the Decision violates Public Utilities Code section 1705, presumably because it does not provide "separately stated . . . findings of fact and conclusions of law by the Commission on all issues material to the order or decision."[16] Again, these allegations fall flat in the face of the extensive findings of fact and conclusions of law by the Commission as to the reasonableness of each separate component of PG&E's projected revenue requirement, [17] the Commission's lengthy discussion of and findings on the various rate design proposals (including Applicants' proposals),[18] and the Commission's order that the approved new transportation rates are to be based directly on the approved revenue requirement and rate design.[19]

In short, the Decision clearly recognizes that the rates resulting from the approved revenue requirement and rate structure are just and reasonable. Applicants' argument—that the Commission's conclusions as to the reasonableness of PG&E's revenue

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14 Decision at 327 ("All else being equal, a single rate would lower local transmission rates and increase rates for backbone-connected customers.").

15 Application at 9.

16 Application at 9; Pub. Util. Code § 1705.

17 *See*, *e.g.*, Decision at Findings of Fact 160, 165, 168, etc.; *id.* at Conclusions of Law 5, 11, 33, 38, 47, 48, 49, 53, 57, etc.

18 Decision at 289 – 342.

19 Decision at Ordering Paragraph 4.

requirement and rate design do not support the reasonableness of the resulting rates—fails to recognize the plain and simple logic of the Decision and the Commission's longstanding process for setting rates: first the utility's overall revenue requirement is determined, and then a rate design is chosen that allocates that revenue requirement to the customer classes and determines the final rates for each such class.

b. The Commission's Consideration of Rate Impacts Evidences Its Conclusion that the Approved Rates are Just and Reasonable

Aside from failing to recognize that the Decision, clearly found that the rates resulting from the adopted revenue requirement and rate design are just and reasonable, Applicants also fail to acknowledge that the Commission expressly considered the resulting rates associated with the adopted revenue requirement and rate structure, and adopted measures to mitigate cost increases. For example, the Decision states that "customer affordability must be considered in determining the reasonableness of PG&E's requested revenue requirement."[20] Accordingly, the "Decision makes various adjustments to PG&E's forecast in instances where [the Commission] found PG&E's forecast to be unreasonable, adopted disallowances as warranted, and slowed the pace of work where appropriate."[21]

While Applicants may prefer that the Commission had further mitigated rate increases for EG-LT customers, the Decision concluded that further rate impact mitigation must be balanced against the need for additional investments in the safety of the local transportation system:

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[20] Decision at 30.
[21] Decision at 30.

> There is no dispute that PG&E's requested revenue requirement is unprecedented. At the same time, there is no dispute that the scope of work to be performed is necessary to comply with new federal and state safety mandates. . . . While we agree that customer affordability must be considered in determining the reasonableness of PG&E's request, we must also balance that against the requirement that PG&E "furnish and maintain such adequate, efficient, just, and reasonable service . . . as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." [Pub. Util. Code § 451.] Thus, while there is a significant increase in the revenue requirement during this Rate Case Period, this increase reflects the significant increase in work to be performed to meet new, heightened safety requirements.[22]

Accordingly, the Commission concluded that, "[i]n determining the reasonableness of PG&E's requested revenue requirement, the Commission must consider affordability along with the mandate that PG&E comply with new, heightened safety requirements."[23]

Nevertheless, in an effort "to mute the rate impacts on customers," the Commission took several actions. For example, it extended PG&E's current gas transmission and storage ("GT&S") rate case period from three to four years by adopting a third attrition year for this Rate Case Period.[24] Thus, PG&E generally will not have an opportunity to add costs to its revenue requirement, beyond those allowed through the attrition process, until its next rate case period commencing in 2019. The Commission also amortized over 36 months PG&E's collection of the difference between the new rates authorized by the Decision and the "placeholder" rates collected during the

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22 Decision at 31.
23 Decision at 441, Conclusion of Law 8.
24 Decision at 31; *id.* at 410 – 412.

pendency of this proceeding.[25] The Decision also notes that the $850 million penalty imposed on PG&E in connection with the San Bruno incident will further reduce rate impacts.[26] Moreover, the Commission disallowed recovery of PG&E costs due to delays in the proceeding caused by PG&E' s violation of *ex parte* rules, which the Commission noted "is an equitable remedy to address the impact of PG&E' s violation, and the corresponding five-month delay in this proceeding, on ratepayers.[27]

Elsewhere, the Application provides a list of mechanisms by which the Commission purportedly could have mitigated rate impacts caused by PG&E' s increased revenue requirement, arguing that the Decision has failed to consider these mechanisms.[28] Applicants are mistaken; the Commission reviewed these proposals, adopted some and rejected others. For example, Applicants highlight proposals from TURN and others that PG&E shareholders bear a greater portion of new safety costs.[29] However, the Decision expressly considers these proposals, and rejects them.[30]

Applicants note proposals that revenue needs for safety projects that can be deferred to future rate case cycles should be excluded from the adopted revenue

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[25] Decision at 31-31.
[26] Decision at 332 (citing D.15-04-024 ("Penalties Decision")).
[27] Decision at 281.
[28] Application at 16-17.
[29] Application at 16, first bullet.
[30] Decision at 31 (Noting that "Intervenors have recommended that in order for the proposed rate increases to be reasonable, PG&E shareholders must bear a greater share of the forecast costs", and declining to adopt these proposals).

requirement.[31] But the Decision indicates that it has in fact "slowed the pace of work where appropriate" in response to concerns over "customer affordability."[32]

Applicants note further that the Decision should defer cost recovery.[33] However, Applicants fail to appreciate that the Decision does exactly this by amortizing over 36 months PG&E' s recovery of the difference between the authorized revenue requirement and the placeholder revenue requirement.[34]

Applicants also refer to proposals that revenue recovery for costs associated with Line 407 be treated as a "rate adder" and not included in rate base until that project is complete.[35] But Applicants fail to acknowledge that the Decision expressly adopts this very proposal.[36]

Applicants argue further that PG&E' s return on equity should be reduced,[37] notwithstanding that NCGC witness Ms. Falcon admitted that "PG&E' s allowable ROR is not part of this rate case" and proposed adjusting PG&E' s allowable rate of return in PG&E' s next rate case, not the present proceeding.[38] Not surprisingly, the Commission did not adopt such a proposal in this proceeding.

In light of the Decision' s extensive treatment of rate impact mitigation, it cannot be seriously argued that the Decision fails to consider the reasonableness of resulting rates. The Commission' s discussion of rate impacts to customers, and the countervailing

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31 Application at 16 (second bullet) and 17 (third bullet).
32 Decision at 30.
33 Application at 17, second bullet.
34 Decision at 31-32.
35 Application at 17, fifth bullet.
36 Decision at 228, *id.* at 427, Finding of Fact 130.
37 Application at 17, eighth bullet.
38 NCGC-1 (Falcon) at 23 – 24.

need for investments in the safety of PG&E' s system, clearly evidences the Commission' s consideration of the rates approved in the Decision, and its conclusion that the approved rates represent a just and reasonable balance of competing policy goals. This balance of competing interests is exactly the kind of determination that is within the Commission' s expert purview; in this respect, the Commission' s conclusions are final.

c. In Arguing that the Adopted Rates are Not Just and Reasonable, Applicants are Plainly Attempting to Re-Litigate their Proposals for Alternative Rate Structures Designed to Subsidize EG Customers on the Local Transmission System

Applicants argue that, "[i]f the sheer magnitude of the revenue requirement combined with the adopted rate design results in rates that are not just and reasonable, the Commission must adopt an alternative rate design that can produce just and reasonable rates."[39] In so arguing, Dynegy and NCGC are plainly attempting to re-litigate their proposals for new rate structures that shift costs associated with PG&E' s local transmission system to EG-BB customers who do not use, and have never used, that infrastructure.

The Decision clearly reflects that the Commission considered Dynegy and NCGC' s claim that the rates proposed by PG&E would be unjust and unreasonable along with their proposals for new EG rate structures. The Commission rejected those proposals as unfair and not consistent with the Commission' s longstanding adherence to cost causation principles.[40] For example, in rejecting NCGC and Dynegy' s argument that the existing rate structure with separate rates for BB and LT-connected EG customers

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[39] Application at 8.
[40] Decision at Conclusions of Law 245-254.

unduly restricts the competitiveness of LT-connected EG customers, the Commission found that "[c]ompetition is enhanced when competitors pay cost based rates for essential utility services."[41]

As to their primary rate design proposal to adopt a single rate for all EG customers, the Commission rightly concluded in the Decision that "[i]t would be unfair to require all EG customers to pay the same transportation rate, regardless of whether they connect to PG&E' s system at the backbone or at the local transmission level."[42] This is so because "backbone-level customers do not use the local transmission system, and do not cause local transmission costs to be incurred. Such customers should not be forced to pay the costs of the local transmission system which they do not use, thereby subsidizing EG units located on the local transmission system that are more costly to serve."[43] Separate rates for EG-BB and EG-LT customers is therefore "consistent with principles of cost causation." Further, separate rates for EG-BB and EG-LT customers "provides an incentive for new gas-fired generation plants to interconnect directly to the backbone system where PG&E can more easily manage changes in the flow of gas."[44]

Dynegy and NCGC also offered several other proposals that would subsidize electric generation facilities on the local transmission system at the expense of electric generators that do not use the local transmission system. For example, Dynegy proposed four alternatives: (1) a bill credit for EG-LT customers, and a bill credit just for

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41 Decision at 333.
42 Decision at Conclusion of Law 246.
43 Decision at 327-328.
44 Decision at 327 (citing PG&E-40 (Armato) at 10-20).

Dynegy's Moss Landing Units 1 and 2, (2) new rate-classes that would benefit its electric generating facilities taking service from the local transmission system, (3) Dynegy's purchase of Line 301-G from PG&E, and (4) long-term discounted contracts for service to Dynegy's Moss Landing Units 1 and 2.[45] NCGC also offered two additional proposals, (5) that the Commission allow existing EG-LT customers to construct lateral pipeline connections to PG&E's backbone system and qualify for the EG-BB rate, and (6) reclassify certain PG&E local transmission pipelines as part of the backbone system.[46] The Commission considered each of these six proposals, and rejected them, either because they were not supported by the record, were not fair or consistent with principles of cost-causation, were not the appropriate subject of a gas transmission rate-setting proceeding, or were inconsistent with the Commission's distinction between the backbone and local transmission systems.[47]

In short, the Commission has already considered Applicants' claims regarding, and proposals to mitigate, rate impacts on local transmission-connected electric generators, and refused these proposals as neither fair to backbone-connected EG customers nor desirable from a public policy standpoint. The Commission should likewise refuse Applicants' attempt to re-litigate the same proposals on rehearing.

d. Applicants Are Wrong that the Decision Relies on the "Interim" Status of the Approved Rates

Applicants argue that the Decision justifies the increase in rates on the basis that the rates are "interim," in that rates may be adjusted downward when the Commission

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[45] Decision at 334.
[46] Decision at 334.
[47] Decision at 334-338; *id* at Conclusions of Law 247-254.

applies the San Bruno penalty and/or the disallowance for delays due to *ex parte* rule violations.[48] They note that, during the interim period before the penalty and disallowance are applied, they will be negatively impacted by increased rates.[49]

This argument is entirely specious. Applicants do not cite any language in the Decision indicating that the Commission relied on the effect of the penalty or delay disallowance to justify the "interim" rates as reasonable. Though it is indisputable that the $850 million penalty for the San Bruno incident, and the $137,840 million disallowance for delay caused by PG&E's violation of *ex parte* rules, *will* mitigate rate impacts to EG-LT customers to some degree (it remains to be seen by how much), the Decision nowhere relies on the San Bruno penalty or the delay disallowance to conclude that the adopted rates are just and reasonable. As discussed above, the Commission's judgment that the revenue requirement and rate structures are just and reasonable, and its effort to balance rate mitigation with the need for safety investments, undergird its conclusion that the approved rates are just and reasonable. The Commission is right to comment on the penalty and the delay disallowance in connection with rate impacts, and

48 Application at 10-12.

49 In making this argument, Applicants make several assertions that are not supported by the record. For example, Applicants assert without citation to the record that "a local transmission generation unit" may not be dispatched by the California Independent System Operator ("CAISO") "because its bid in the day-ahead and real-time electricity markets "is too high due to the costs of gas transportation." Applicants' assertions run contrary to the testimony of their own witnesses, which demonstrates that CAISO may dispatch units even if their bids do not clear the market, and that facilities may enjoy substantial revenues in such circumstances. See, e.g. Reporter's Transcript at 4318:2 – 9 (Dynegy witness Mr. Isemonger testifying that power plants are able to earn material revenues outside of CAISO's energy markets, including by selling ancillary service products and resource adequacy products).

it does not rely on the penalty or delay disallowance to justify the rates as just and reasonable.

In sum, Applicants primary argument for rehearing—that the Commission did not make separate findings as to the reasonableness of rates—ignores the Decision's detailed findings as to the reasonableness of PG&E's revenue requirement and rate structures, and the Decision's finding that these factors directly determine PG&E's rates. The Applicants altogether ignore the express statements in the Decision showing that, in adopting the revenue requirement and rate structures for PG&E, the Commission also considered and approved the resulting rates. And, with respect to the EG-LT rates with which the Applicants are primarily concerned, Applicants ignore the lengthy discussion in the Decision as to the claims by Applicants concerning rate impacts and rate design.

Applicants' request for rehearing is not based on a substantive deficiency in the Commission's Decision or the record, but instead is a plain attempt to re-litigate their requests for a new rate structure that would subsidize their electric generation facilities which rely on PG&E's local transmission system. "Rehearing applications are not a proper vehicle to merely reargue positions taken during a Commission proceeding".[50] Accordingly, Applicants' request for rehearing should be denied.

2. Applicants' "Rate Shock" Arguments Fail

a. The Commission's Exercise of its Broad Rate-Setting Discretion in this Proceeding Falls Within a "Zone of Reasonableness" for Commission Decisions

Applicants argue that the rate increases approved by the Decision will result in

[50] D.16-05-053 at 12 (citing D.12-12-040 at 3).

"rate shock" to the EG-LT customer class, which the Commission allegedly failed to adequately address.[51] This argument is fundamentally the same as Applicants' argument that the rates are not just and reasonable, and for the reasons discussed above, fails to justify rehearing. As explained more fully above, the Decision reflects that the Commission thoroughly considered the various components of PG&E's revenue requirement, disallowed certain revenue proposals, and otherwise mitigated increases in PG&E's revenue requirement (and the resulting rates) to the extent fair and feasible. The Decision also reflects that the Commission considered Applicants' alternative rate design proposals, by which Applicants attempted to lower their rates by shifting costs to EG-BB customers.

Applicants invoke the phrase "rate shock" numerous times in the Application, as if an increase to any utility rate of a certain magnitude always requires the Commission to abandon cost causation principles and to adopt measures to mitigate rate impacts. This is not the case. As the Commission has long explained, departing from cost causation principles to mitigate rate impacts is typically an "extraordinary remedy"[52] which the Commission may, or may not, exercise in its "broad ratemaking discretion."[53] The Commission's "ratemaking determinations will be upheld so long as they fall within a broad `zone of reasonableness'."[54] The Commission's approval of the EG rates and rate structure in the Decision fall well within this "zone of reasonableness."

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51 Application at 12-18.

52 D.88-09-037, 29 CPUC 2d 374 (1988) at *4 (declining to adopt rate cap to mitigate rate increases experienced by electric generation customer class).

53 D.88-03-076, 27 CPUC 2d 558 at *5.

54 *Id.*

b. The Past Commission Decisions Cited by Applicants Are Not Applicable and Do Not Require the Commission to Further Mitigate Rates in This Proceeding

Applicants rely on several past Commission decisions in their attempt to make their "rate shock" arguments. However, the decisions cited by Applicants do not apply to the case at hand and only underscore that the Commission has acted well within the permissible scope of its broad rate-making discretion in this proceeding.

First and foremost, each of the three decisions cited by Applicants on the issue of "rate shock" concern the *total* cost of electricity service to the affected customers.[55] As the Commission is well aware, electricity rates bundle together the cost of electricity transmission and the cost of the electric commodity itself. Here, unlike in the cases cited by Applicants, the rate at issue—the G-EG/LT rate—represents only a portion of electric generation customers' gas transportation costs,[56] and an even smaller portion of their total burnertip gas costs. Importantly, Dynegy witness Mr. Isemonger acknowledged under cross-examination that, for purposes of assessing the impacts of rates on electric generation customers, "the all-in [gas] cost is the most important cost."[57] Thus, the raw percentage rate increases cited by Applicants as constituting "rate shock" in prior cases are not directly applicable or comparable to this proceeding, where the Commission is considering only the costs of local transmission—a relatively small portion of customers' total gas costs. For this reason, a 200% increase in the G-EG/LT rate is not *prima facie* evidence of "rate shock."

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55 *See generally* D.11-05-047 (concerning PG&E residential electricity rate), D. 09-10-028 (concerning Bear Valley Electric Service rates), and D.90-12-066 (concerning PG&E electricity rates).

56 *See* Decision at Finding of Fact 201.

57 Reporter' s Transcript at 4327:12 - 16 (Dynegy/Isemonger).

In addition, each of the decisions cited by Applicants are not applicable for several other reasons. For example, applicants cite Decision 11-05-047 for the proposition that a 50% rate increase could constitute undue rate shock. [58] In that case, however, the Commission was focused on mitigating rate impacts to low income residential customers.[59] Low-income residential customers are substantially more vulnerable to cost increases than the EG-LT customer class, which is comprised of sophisticated gas consumers and investors that the Decision notes should have been aware of the existing rate structure, should have understood their exposure to local transmission rate increases, and could have anticipated the risk of a growing differential between the rates for EG-LT and EG-BB customers.[60] Applicants also fail to note that the rate mitigation adopted by the Commission in Decision 11-05-047 more closely aligned the rate structure with cost causation principles, rather than deviating further from those principles. [61] By contrast, the remedies proposed by Applicants in this proceeding would have had the Commission drastically depart from traditional cost causation principles. The Commission rightly determined that Applicants' proposals for alternate rate structures, which would have shifted the costs of PG&E's increased revenue requirement from EG-LT customers to EG-BB customers, would represent an unfair and unwarranted subsidy that departs from cost causation principles. [62]

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[58] Application at 12.
[59] D.11-05-047 at Conclusion of Law 11.
[60] Decision at 330.
[61] D.11-05-047 at Finding of Fact 20 and Ordering Paragraph 12.
[62] Decision at 327 - 328.

Similarly, in Decision 09-10-028,[63] the Commission considered a proposal to transition from the "system average percent" methodology to an "equal percentage marginal cost" ("EPMC") ratemaking approach, resulting in a rate increase to residential customers. [64] The Commission "balance[d] other considerations against the goal of EPMC" and determined that the proposed rate increase for residential customers was inappropriate at that time.[65] The Commission' s task of balancing the rationales behind various rate-setting methodologies in Decision 09-10-028 is quite different than the Commission' s effort to balance rate impacts against the need for capital investments in safety programs in this proceeding. As the Decision noted, the need for PG&E to make significant capital outlays to meet new State and federal safety regulations is imperative, and justifies the unprecedented increase in PG&E' s revenue requirement.[66] Thus, Decision 09-10-028 is not applicable to the instant proceeding. Decision 09-10-028 also concerned rate increases for residential customers, and so, for the reasons stated above, is not applicable to rate impacts on Applicants, who are better able to absorb rate increases, and, as the Decision notes, should have foreseen that they were at risk for such increases should they occur. [67]

The only decision cited by Applicants in support of their "rate shock" arguments in which the Commission addressed rate impacts to non-residential customers is

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[63] Cited in Application at 14.
[64] D.09-10-028 at 7.
[65] *Id.*
[66] Decision at 31.
[67] Decision at 330.

Decision 90-12-066.[68] That decision also concerned the application of EPMC, and concluded that a rate increase to agricultural customers caused by the new application of EPMC rate-setting methodology "does not represent a reasonable balancing of our ratemaking goals."[69] As discussed above, balancing the interests associated with different rate-setting methodologies is quite different than balancing rate impacts against the imperative need for investments in safety infrastructure, as the Commission is tasked with doing in the instant proceeding.

The Commission also noted in Decision 90-12-066 that it was not bound to replicate prior rate mitigation efforts for the same customer class, but instead that "in this proceeding we must strike a balance based on all of the facts before us this year . . . ."[70] The Commission further advised that it was "not fully convinced that such increases cannot or should not be tolerated in future years."[71] "We cannot simply accept [a party' s] assertion about rate shock that `you' ll know it when you see it' ."[72] Thus, the Commission required parties in the future to "present specific evidence" demonstrating that departure from the prevailing rate structure is appropriate, such as "objective data on the demand [for electricity] of the agricultural class".[73] These statements evidence the Commission' s reluctance to mitigate rate impacts to commercial customer-classes, as opposed to more vulnerable residential customers, and its refusal to accept assertions of "rate shock" at face value, but instead to require objective economic data justifying rate

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68 Application at 12-13.
69 D.90-12-066, 38 CPUC 2d 432, at Finding of Fact 19.
70 *Id.* at *10.
71 *Id.* at *100.
72 *Id.* at *11-12.
73 *Id.* at *11-12.

intervention. As discussed more fully below, the Commission did consider objective data on the economic impacts of various rate structures for electric generation customers in the instant proceeding, and found that deviation from cost causation principles to protect EG-LT customers was not warranted.

c. The Decision's Characterization of the Change in PG&E's Revenue Requirement is Accurate and Reasonable

Applicants argue that, in an effort to mask the full effect of the Decisions' rate increases, the Commission understates the rate increase by comparing approved rates with 2014 rates that included costs associated with PG&E's Pipeline Safety Enhancement Plan ("PSEP") approved in Decision 12-12-030.[74] Applicants imply that this was an intentional effort by the Commission to obfuscate the magnitude of their rate shock concerns expressed in this proceeding. Of course, Applicants fail to consider the Decision's forthright consideration of the rate impacts at issue here, and the extensive findings as to the reasonableness of the revenue requirement, rate structures, and the rate impact mitigation approach taken. The Commission fully acknowledged that "PG&E's revenue requirement is unprecedented," but noted that it was just and reasonable in this case under the circumstances.

Moreover, the comparison cited by Applicants is not the basis on which the Commission concluded that there is no need for further cost mitigation. As discussed above, the Commission engaged in a lengthy and complex analysis of PG&E's proposals,

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[74] Application at 15, first bullet (citing Decision at 2-3, summarizing revenue requirement increases over prior years).

and balanced revenue needs with rate mitigation concerns. The comparison cited by Applicants is simply an illustration of the several rates being adopted.

Even assuming that the Commission's comparison of the approved revenue requirement to the 2014 revenue requirement is material to the Commission's resolution of this case, Applicants provide no rationale for why PSEP costs should be excluded from the basis of comparison. Indeed, PG&E's revenue requirement including PSEP costs is a fairer comparison to the revenue requirement approved in the Decision, as both revenue requirements reflect the costs of significant new safety investments, and the comparisons show the rate change as compared to the most recently-adopted rates.

Applicants argue further that the Decision is flawed because it describes the increase in revenue requirement after taking into account a placeholder disallowance of $192.967 million for PG&E's *ex parte* violations.[75] They argue that "any reduction resulting from the imposition of penalties to be borne by PG&E's shareholders is irrelevant."[76] In the context of Applicants' larger claim of "rate shock," this argument is absurd. Disallowances from PG&E's revenue requirement will be applied to reduce Applicants' rates from what they otherwise would have been. Any downward adjustments to PG&E's revenue requirement—including adjustments for penalties—are therefore indisputably relevant to the question of whether the Decision causes Applicants to experience supposedly impermissible "rate shock."

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[75] Application at 15, second bullet.
[76] Application at 16.

d. The Commission Was Not Obligated to Adopt All Rate Mitigation Proposals Proposed by the Parties

The Application provides a list of mechanisms by which the Commission could allegedly have mitigated rate impacts caused by PG&E's increased revenue requirement, and implies that this refusal to further mitigate rates constitutes legal error in the face of what Applicants view as *prima facie* rate shock.[77] As discussed above, Applicants are mistaken that the Commission did not review and rule on the appropriateness of these rate mitigation measures. In fact, the Commission reviewed many of these proposals, adopted some and rejected others.

In any event, Applicants' list of mechanisms by which the Commission could allegedly have mitigated rate impacts is another attempt to re-litigate arguments that have already been rejected by the Commission. The Commission's judgment as to the reasonableness of rates resulting from PG&E's revenue requirement was well within the "zone of reasonableness" that sets the bounds of the Commission's broad ratemaking discretion.

3. The Commission Assessed Economic and Competitive Impacts of the Proposals Before It, and Rightly Determined that Mitigation Was Not Necessary

Applicants argue that the Commission's Decision failed to consider or address the economic or competitive impacts of increased gas transmission rates on California's electricity market. As explained fully below, Applicants are wrong. The Commission

[77] Application at 16 - 17.

clearly did consider the economic and competitive impacts of its Decision, and (as noted above) mitigated those impacts to the extent mitigation was just and reasonable.

a. The Commission Considered the Economic Impacts of the Rate Proposals Before It

Public Utilities Code section 321.1(b) requires the Commission to "take all necessary and appropriate actions to assess the economic effects of its decisions and to assess and mitigate the impacts of its decision on customer, public, and employee safety." Section 321.1(a) clarifies that "[i]t is the intent of the Legislature that the commission assess the economic effects or consequences of its decisions as part of each ratemaking, rulemaking, or other proceeding, and that this be accomplished using existing resources and within existing commission structures." As Applicants note, section 321.1(b) does not require the Commission to perform a separate cost-benefit analysis or consider the economic effects of a decision on specific customer groups or competitors.[78] Applicants nevertheless argue that the Decision fails to meet the requirements of section 321.1 by not assessing or mitigating the economic impacts of the adopted rates on California electricity markets.[79]

Contrary to the Applicants' arguments, the Commission did consider the impacts of the proposals before it on California's electricity markets, reviewing testimony on this subject by witnesses for PG&E, Calpine, the Applicants, and other parties. That evidence, summarized below, amply supports the Commission's conclusion that the

78 Application at 19, n. 53 (citing D.06-12-042).
79 Application at 19-21.

approved revenue requirement does not unacceptably impact wholesale electricity markets.

i. The Commission Considered Evidence Presented by PG&E Witness Mr. Hatton on Effects of PG&E's Proposed Rates to the Wholesale Electricity Market

PG&E witness Mr. Hatton presented the results of a computer simulation that modeled the comparative economic effects of the two EG rate structure proposals before the Commission in this proceeding: (1) PG&E' s proposal to continue the existing rate structure, with separate rates for EG-BB and EG-LT customers, and (2) the competing proposal from Dynegy and NCGC for a single rate for all electric generators.[80] After discussing the analysis provided by PG&E witness Mr. Hatton, the Decision determined that his analysis demonstrated that neither proposal would significantly increase marginal costs in the wholesale electric market, as compared to the competing rate structure.[81]

Applicants argue that "PG&E' s comparison of its proposed rates and a single EG rate is not an analysis of the impacts of this revenue requirement on wholesale electric rates."[82] This assertion is simply false. Mr. Hatton modeled wholesale electric rates on the basis of PG&E' s proposed 2015 rates, and concluded that "[w]ith PG&E[`s] proposed EG rate structure the average annual marginal cost of power is $33.73/megawatt-hour (MWh) . . . ."[83] Although Mr. Hatton used this analysis in a comparison against the marginal cost of power resulting from Dynegy and NCGC' s rate design proposal, his

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80 PG&-43, Ch. 17B (Hatton).

81 Decision at 331 (citing Reporter' s Transcript at 4363:19 – 4364:2 (Dynegy/Isemonger); *id.* at 5365:3-13 (NCGC/Falcon); PG&E-43 Ch. 17B (Hatton) at 17B-4 - 17B-5).

82 Application at 28.

83 PG&E-43 Ch. 17B (Hatton) at 17B-5:19 – 21. Mr. Hatton went on to compare this outcome with the effect of a single EG rate on wholesale energy markets.

computer modeling plainly includes an analysis of the impacts of PG&E's revenue requirement on wholesale electric rates.

Applicants complain that Mr. Hatton was "unfamiliar with factors used in electricity pricing relevant to hourly marginal energy costs,"[84] and argue that this undermines the value of his testimony on the impacts to wholesale electricity markets of increased EG gas transmission rates. Effectively, Applicants extrapolate from Mr. Hatton's statement on cross-examination that he is a resource planner and is not familiar with PG&E's "default load aggregation price," which is one particular price benchmark in the complex electricity market, the false conclusion that he is not qualified to testify about marginal energy costs and the factors used in electricity pricing.[85] But Applicants offer no support for the proposition that, in order to perform an appropriate analysis of the effect of changes in gas rates on marginal energy prices, a resource planner needs to understand each and every price benchmark employed by participants in the electricity markets. Like any resource planner, Mr. Hatton appropriately focuses on the fundamental market metrics, and adequately explains his modeling methodology in his testimony.[86] In any event, Applicants' criticism of Mr. Hatton's understanding of wholesale electricity markets rings hollow, given the fact that they rely repeatedly on his testimony for his conclusion that the capacity factor for Moss Landing Units 1 and 2 will

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84 *See* Application at 28.

85 Reporter's Transcript at 4057:25 – 4058:7 (PG&E/Hatton).

86 Reporter's Transcript at 4037:6 – 4039:27 (PG&E/Hatton); *see also* PG&E-43 Ch. 17B (Hatton) at 17B-4 – 17B6.

be reduced under the existing rate structure and approved rates, and describe his testimony on this issue as "striking evidence."[87]

In sum, Mr. Hatton clearly provided testimony on the impact of PG&E's proposed rates on wholesale electricity markets. The Commission considered this evidence, and rightly concluded that the approved increase in the revenue requirement would not "result in significant increased marginal costs in the wholesale electric market."[88]

ii. The Commission Rightly Concluded that NCGC and Dynegy Did Not Present Convincing Evidence of Adverse Impacts to the Wholesale Electricity Markets that would Render PG&E's Revenue Requirement Unreasonable

As the Decision notes, in contrast to PG&E, Dynegy and NCGC did not submit evidence on how their rate restructuring proposals would affect wholesale electric prices in California.[89] On cross-examination, NCGC witness Ms. Falcon admitted that she did not attempt to quantify, or substantiate with analysis, the effects of either PG&E's or NCGC's rate proposal (or the resulting rates) on wholesale prices for electricity.[90] Instead of providing economic analysis of the impact of rates or rate structures on the larger wholesale electricity market, as PG&E provided, NCGC and Dynegy focused much of their testimony—and many of their arguments in their Application for Rehearing as well—on impacts to the plants that they own.[91] In response to this evidence, the

87 Application at 26.
88 Decision at 331.
89 Decision at 331.
90 Reporter's Transcript (NCGC/Falcon) at 5363:18 – 5365:13.
91 E.g., Application at 29 ("Many generators served by the local transmission system will be unable to compete in electricity markets at commercially sustainable levels.").

Decision concludes aptly that "impacts on *individual* generators would not impair the efficiency of the overall market."[92]

iii. The Commission Considered Evidence from Several Parties on the Multiplier Effect, and Rightly Concluded that Impacts to Wholesale Electricity Markets Caused by Increased Gas Transportation Rates Do Not Warrant Further Mitigation of Rates

Applicants argue that "[t]he Decision unlawfully ignores all evidence regarding the `multiplier effect.' "[93] To the contrary, the Decision expressly acknowledges NCGC' s argument that the differential between rates for BB and LT customers will "produce a multiplier effect that will increase the cost of electricity disproportionately to the increase in gas transportation costs to electric generators."[94] Having noted this, the Decision goes on to conclude on the basis of substantial evidence that the claim made by NCGC, Dynegy and others about impacts to the electricity market are not persuasive.[95]

The record amply supports the conclusion that even with a "multiplier effect," the impact of increases in gas transport costs on the wholesale electricity market does not render the revenue requirement, rate design or rates adopted in the Decision unreasonable, or warrant additional mitigation of certain electric generators' gas transportation rates. For example, in response to Indicated Shipper' s Witness Mr. Lesser' s testimony that the multiplier effect could magnify increases in electric generators' marginal costs in the electricity market by up to a factor of six,[96] Calpine

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92 Decision at 332.
93 Application at 25, first bullet.
94 Decision at 323.
95 Decision at 331, *id.* at 332.
96 Indicated Shippers-6 (Lesser) at 17-19.

witness Mr. Beach testified that Mr. Lesser significantly overstated the multiplier effect by assuming that gas fired generators will set the electricity price in every hour, an unrealistic assumption.[97] Mr. Beach suggested that any "multiplier effect" will more likely have impacts of only 2.3 times the increase in total gas costs. Similarly, Southern California Generation Coalition ("SCGC") witness Ms. Yap testified about the multiplier effect in her testimony defending PG&E' s proposal to equalize Baja and Redwood path rates.[98] On cross examination, however, Ms. Yap admitted major flaws in her analysis, including that much of the electricity supplies that she assumed would be priced at increased spot-market electricity market clearing prices would not, in fact, result in higher electricity costs to electricity customers, either because the electricity was supplied by utility-owned generation or by renewable generators under long-term contracts.[99] The Commission heard this evidence and, on balance, concluded that any adverse impacts to the wholesale electricity market do not warrant further rate mitigation, or render the approved rates unjust or unreasonable. This conclusion is well within the Commission' s discretion; "When conflicting evidence is presented from which conflicting inferences can be drawn, the [Commission' s] findings are final."[100]

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97 Calpine-1 (Beach) at 28:19-21.

98 SCGC-2 (Yap) at 3-8.

99 Reporter' s Transcript at 3516-3535 (NCGC/Yap).

100 *Clean Energy Fuels Corp.* (2014) 227 Cal. App. 4th at 649-650 (citing *Toward Utility Rate Normalization v. Pub. Util. Comm'n* (1978) 22 Cal. 3d 529, 537–538).

iv. Evidence on Total Marginal Cost Increases to Electric Generators Does Not Support Applicants' Claim that the Approved Rates Will Cause Unreasonable Adverse Impacts to Wholesale Electricity Markets

The record is replete with evidence that supports the Commission's determination that PG&E's increased revenue requirement is reasonable, notwithstanding increases in electric generators' marginal costs. First, as the Commission found (and as discussed above in the context of Applicants' "rate shock" arguments), the transmission rates paid by electric generators under the EG-LT or EG-BB rates are not the only gas transportation cost incurred by electric generation plants.[101] Electric generators taking transportation service from PG&E also pay (either directly or indirectly) the cost of transportation on PG&E's backbone system.[102] Further, EG-BB customers must pay to build, operate and maintain their lateral connections to PG&E's backbone system, effectively paying for their own local transmission systems.[103] As the Commission noted, these other transportation costs can vary considerably according to an electric generation plant's location and particular infrastructure decisions,[104] and can have the effect of reducing the relative significance of increases to the EG-LT rate.[105]

Second, as discussed above, gas transportation costs are only part of a gas-fired electric generator's total burnertip gas costs, for commodity costs also must be incurred

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101 Decision at Finding of Fact 201.

102 Decision at Finding of Fact 182.

103 Decision at Finding of Fact 200; *see also* SMUD-1 (Ingwers) at 12 ("[T]he costs of owning and operating the SMUD local gas transmission system are significant. As mentioned before, SMUD spent over $90 million in capital costs to build its local gas transmission system and continues to pay approximately $2.5 to $3.0 million per year in ongoing Operating and Maintenance costs.").

104 Decision at 332-333.

105 *Id.*

by electric generators. Dynegy witness Mr. Isemonger testified on cross that, for purposes of assessing the impacts of rates on electric generation customers, "the all-in [gas] cost is the most important cost."[106]

Third, total gas costs are only a portion of the total marginal costs of generation. Indeed, as noted by Dynegy and NCGC in their Application for Rehearing, NCGC's witness testified that the approved rate increases, before any mitigation associated with the San Bruno penalty or *ex parte* disallowance, would cause only a 10% increase in NCGC's marginal cost of production, assuming average marginal costs of $40 to $45 per megawatt-hour ("MWh").[107] This is clear evidence that the costs of gas transportation are only a part of electric generators' costs of production, and that increases in the transport costs borne by Applicants' facilities do not result in total marginal cost increases of the same magnitude that the Applicants cite as examples of "rate shock."

Fourth, electric generators taking gas transportation service from PG&E represent only a portion of the electric generators serving the electricity demands of the State.[108] A number of electric generation plants in California have chosen to locate near, and have directly connected to, interstate gas pipelines, and so do not take service from PG&E.[109] Similarly, electric generators connected to the SoCalGas system also will not see an increase in gas transport costs as a result of the Decision.[110] Of course, out-of-state

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106 Reporter's Transcript at 4327:12-16 (Dynegy/Isemonger).
107 Application at 20-21 (citing NCGC-1 at 8).
108 Decision at 330 ("For some EG plants, PG&E's rates do not apply at all.").
109 Calpine-1 (Beach) at 13:28 – 14:1; Reporter's Transcript at 4314:3 – 6 (Dynegy/Isemonger).
110 Reporter's Transcript at 4313:26 – 4314:2 (Dynegy/Isemonger).

electric generators, and the State' s growing fleet of renewable generators also will not be significantly impacted by PG&E' s gas transport rates.

Fifth, the spot electrical markets (such as the CAISO' s day-ahead and real-time energy markets, which Dynegy and NCGC focus on) are only a portion of the complex market for electricity in California. As Mr. Isemonger testified, for example, power plants can sell to load-serving entities like PG&E through long-term procurement contracts.[111] In fact, Dynegy has signed two such long-term contracts already.[112] Further, the CAISO provides other markets for reliability and local capacity services that can provide additional revenue streams to generators.[113]

In short, Applicants' arguments inflate the relative importance of gas transportation rates on electricity prices, and oversimplify the complex wholesale electricity market. The Commission considered evidence on the economic effects of PG&E' s proposed rates on those markets, and found the rates to be just and reasonable. The Decision therefore plainly meets the requirements of Public Utilities Code section 321.1. Dynegy and NCGC' s request for rehearing on the ground that the Decision does not adequately consider or mitigate impacts to wholesale electricity markets should be denied.

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111 Reporter' s Transcript at 4318, lines 10-13 (Dynegy/Isemonger).

112 Resolution E-4696, issued January 30, 2015, approved two contracts for Resource Adequacy capacity between Dynegy Moss Landing, LLC and PG&E. Resolution E-4696 at 2. These contracts will provide PG&E with system Resource Adequacy benefits from Moss Landing Unit 1. *Id.*

113 Reporter' s Transcript at 4318:18 – 4319:11 (Dynegy/Isemonger).

b. The Commission Considered the Alleged Competitive Impacts of the Rate Proposals Before It, and Decided Not to Subsidize Applicants' Facilities

i. The Decision Considers Applicants' Competitiveness Concerns, and Rejects Them as Not Warranting Further Rate Mitigation

Confusingly, Applicants argue both that the Decision fails to consider the competitive implications of its approved rates,[114] and that the Decision's findings on the effects of the adopted rates on competition are not supported by substantial evidence in light of the whole record.[115] Setting aside the obvious fact that the latter of these arguments concedes that the Decision does make findings on the competitive impact of rates for electric generation customers, and so undermines the former argument, neither argument holds water individually. The Decision expressly considers and rejects Applicants' argument that the adopted rate structure unduly burdens LT-connected electric generators to their competitive disadvantage, and the record fully supports the Commission's conclusion. In fact, much of the testimony and briefing submitted by NCGC, Dynegy, Calpine and SMUD focused on this exact issue.

The Decision contains eight pages of discussion of the competitive impacts of PG&E's gas transmission rates, particularly in the context of its consideration of Dynegy's and NCGC's proposal for a single rate for electric generation customers.[116] The Commission noted that a single rate for electric generators connected to the backbone and local transmission systems "would lower local transmission rates and

114 Application at 21-23.
115 Application at 23-25.
116 Decision at 326 – 334.

increase rates for backbone-connected customers."[117] Such an arrangement "would be unfair," the Commission concluded, because "PG&E backbone-level customers do not use the local transmission system, and do not cause local transmission costs to be incurred. Such customers should not be forced to pay the costs of the local transmission system which they do not use, thereby subsidizing EG units located on the local transmission system that are more costly to serve."[118]

The Commission went on to reject the complaints of Dynegy and NCGC that higher rates for electric generation customers connected to the local transmission system "places them at an unreasonable competitive disadvantage because their gas transportation costs will be higher than those of backbone-connected customers."[119] The Commission observed that "[b]ackbone-connected customers bear the equivalent of local transmission costs (via the laterals that connect their plants to the backbone system). Thus, it would not be fair for backbone-level customers to pay both the costs of their own facilities to connect to the backbone plus the costs of PG&E' s local transmission facilities."[120] Indeed, evidence indicates that the costs paid by backbone-connected customers to construct, operate, and maintain their lateral connections to the backbone system can be significant.[121]

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117 Decision at 327.
118 Decision at 327-328.
119 Decision at 328.
120 Decision at 328; *id.* at Finding of Fact 199.
121 SMUD-1 (Ingwers) at 12 ("[T]he costs of owning and operating the SMUD local gas transmission system are significant. As mentioned before, SMUD spent over $90 million in capital costs to build its local gas transmission system and continues to pay approximately $2.5 to $3.0 million per year in ongoing Operating and Maintenance costs.").

ii. Applicants Oversimplify Market Dynamics

That separate rates for backbone and local transmission-connected electric generation customers does not give backbone-connected customers an unfair competitive advantage is evidenced by the fact that Applicants invested in many of their local transmission-level plants well after they became aware of this rate structure, and knew or should have known of the potential for a widening differential between the two rates. The Commission acknowledged this in its Decision. First, the Commission discussed the incremental unbundling of backbone and local transmission services during the 1990's and early 2000's.[122] The Commission noted that, while the final unbundling of EG-AOC and EG-BB rates occurred in 2005,[123] Dynegy acquired Moss Landing Units 1 and 2 in 2007, and several of the NCGC members were similarly aware of the existing rate structure when they built their gas-fired plants.[124] Given that the existing rate structure was in place before Applicants invested in their facilities connected to the local transmission system, and the "gradual incremental pace of rate unbundling," the Commission found "no basis for claims of unfairness in terms of the impacts of the bifurcated rate structure on competitors' business planning and investment over time."[125]

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122 Decision at 329-330. Applicants have throughout this proceeding incorrectly asserted that the current rate structure was the product of settlement. This is not accurate. The existing EG rate structure was adopted in Decision 03-12-061 after a litigated proceeding. The only element deferred to the then-subsequent GT&S proceeding, which was resolved by settlement, was the eligibility criteria for the backbone level rate.

123 Decision at 330 (Citing Calpine-1 at 14).

124 Decision at 330 (Citing Calpine 1 at 14 and NCGC-8).

125 Decision at 330.

Further, as discussed more fully above, the Commission found that "EG rates are not the sole gas transportation cost incurred by EG plants,"[126] and the record supports this conclusion. The Commission also recognized that "[o]ther features affect competition, many of which may dilute or offset competitive impacts of transmission costs."[127] The record indicates that these other factors can be numerous and complex, including costs for interconnection to the gas and electrical systems,[128] site-specific advantages such as the availability of water for once-through cooling[129] and the ease of obtaining various permits,[130] the CAISO's Locational Marginal Price system, which provides higher prices for facilities located close to load centers,[131] and the availability of favorable financing mechanisms, such as the issuance of tax-exempt municipal bonds available to municipal

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[126] Decision at Finding of Fact 201.

[127] Decision at 330.

[128] Calpine-1 (Beach) at 18:7 – 10. Mr. Beach testified that that "[e]xisting gas-fired power plant sites already are connected to the natural gas pipeline system, typically to high-volume, high-pressure transmission lines, and new units at such sites may avoid gas system upgrade costs." The costs of upgrades for new backbone-connected facilities could be significant, while plants such as Moss Landing Units 1 and 2, which were constructed at the site of former gas generation facilities, may not incur any such costs. Mr. Beach similarly testified that "[u]nits developed at existing power plant sites . . . can access the existing electric transmission capacity serving the site and may not need to pay for costly network upgrades and gen-tie lines." Calpine-1 (Beach) at 17:27-30.

[129] Reporter's Transcript at 4306:1 – 11 (Dynegy/Isemonger). Mr. Isemonger testified that Moss Landing Units 1 and 2 are sited near the ocean, and are able to use water for cooling in a process called "once-through cooling." Mr. Isemonger testified that compared to other cooling technologies, once-through cooling is efficient and inexpensive. *Id.*

[130] Calpine-1 (Beach) at 17:15 – 27. Mr. Beach testified that "Local air districts differ in the stringency of the emissions controls that they require and in the cost of offset for criteria pollutants. Similarly, Mr. Beach testified that "Power plant development at brownfield sites long used for power production can offer advantages in terms of land availability and can simplify local zoning and permitting. *Id.* at 18:4 – 6.

[131] Calpine-1 (Beach) at 16:11 – 13. Mr. Beach testified that the CAISO's Locational Marginal Price system generates different market prices for every power plant of material size connected to the CAISO grid. "Generators who are located in or close to load centers (*i.e.* in locations with high LMP prices) benefit from their location under the LMP structure." *Id.*

utilities.[132] As the Commission noted, Dynegy and NCGC' s arguments "have failed to account for such complexities in asserting that transmission rate differentials create impediments to their ability to compete."[133] The Commission stated aptly as follows:

> Fairness is not promoted by altering the playing field in one respect to favor one class of competitors through rate design, while those competitors may enjoy other advantages that are not being addressed. Competition is enhanced when competitors pay cost-based rates for essential utility services.[134]

In sum, Applicants' complaints about impacts to their competitive position relative to other generators are based on a drastically oversimplified characterization of the marketplace. In reality, many factors operate simultaneously to help and/or hinder a given generator' s competitive position; the Commission cannot and should not attempt to "level" this multifaceted playing-field by adjusting one such factor.

iii. The Commission Considered Evidence on a Potential Decrease in the Annual Capacity Factor of Moss Landing Units 1 and 2, and Rightly Found it Did Not Warrant Further Rate Mitigation or Render the Revenue Requirement Unjust

Applicants' arguments about competitive effects of the rates and rate structure approved by the Decision are predicated largely on the testimony of Mr. Hatton, who testified that under PG&E' s proposed rates and rate structure, the annual capacity factor for Moss Landing Units 1 and 2 would be reduced to one percent.[135] Applicants argue

[132] Reporter' s Transcript at 5344:8 – 23 (NCGC/Falcon). Ms. Falcon testified that Tax exempt municipal bonds, which are commonly used by municipal utilities to finance power plants and are not available to non-utility power plant developers, typically have a lower cost than other types of debt available to non-utility developers.

[133] Decision at 331.

[134] Decision at 333.

[135] Application at 25-26 (citing Decision at 33); PG&E-43 Ch. 17B (Hatton) at 17B-4 – 17B-6.

that the Decision errs in dismissing this testimony on the ground that Mr. Hatton's analysis relied on PG&E's original assumptions regarding the magnitude of revenue requirement increases, without considering either that PG&E shareholders must absorb a significant portion of the safety costs, or that the adopted GT&S revenue requirement differs from PG&E's assumptions.[136] Applicants note that the Decision proposes a rate differential between the two EG rates that is larger than the differential assumed by Mr. Hatton in his model.[137]

Applicants' argument (which is fundamentally the same as the one made in each of their comments on the Proposed Decision and Alternate Proposed Decision) does not discredit the Decision's analysis of the competitive effects of the EG rates or rate design. First, the San Bruno penalty and delay disallowance have not yet been factored into the EG rates, and it is undeniable that EG rates—one of the fundamental inputs in Mr. Hatton's analysis—will be impacted when these items are factored in. It still remains to be seen whether the differential employed in Mr. Hatton's analysis was over or understated.

Second, the Decision stated ample other reasons to dismiss Dynegy and NCGC's competition arguments, among them that "any impacts on *individual* generators would not impair the efficiency of the overall market."[138] Thus, even if Mr. Hatton's analysis turns out to have been conservative, the Decision is on solid footing, and the Application should be rejected.

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[136] Application at 26.
[137] Application at 27.
[138] Decision at 332.

iv. Applicants' Laundry-List of Competitiveness Issues Does Not Advance their Argument that Rehearing is Warranted

Applicants' offer an additional laundry-list of issues that the Commission allegedly failed to consider in support of their argument that the Decision unlawfully fails to mitigate competitiveness concerns.[139] Each of these issues is either a regurgitation of the same points offered earlier in this proceeding and rejected by the Decision, or represent new arguments that have no support in the record. None of these issues warrant rehearing.

First, Applicants cite the "drastic change in the dispatch of generators resulting from the differential between transportation rates for EG-BB customers and EG-LT customers," which, according to Applicants, "historically has averaged about 15-20 cents per Dth," and will be 96.74 cents per Dth" under the new rates.[140] Applicants made this same point previously in this proceeding, and the Decision concluded that impacts to LT-connected electric generators under the existing rate structure and PG&E's proposed rates were not unfair.[141] This is consistent with longstanding Commission precedent that its job is to protect *competition* and not *competitors*.[142]

Further, Applicants' figures on the historical differential between backbone and local transmission rates are misleading. In 2013, for example, the rate differential was 28

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139 Application at 22-23.
140 Application at 22, first bullet.
141 Decision at 332.
142 D.97-11-074 ("We fully support the idea that the linchpin of competition policy must be to protect competition and consumers, rather than individual competitors.")

cents per Dth,[143] and in 2014 the differential was 35 cents per Dth. Neither NCGC nor Dynegy provided any evidence that their plants were unable to compete during these time-periods. In fact, Mr. Isemonger' s testimony indicates that when the rate differential expanded in 2012, 2013, and 2014, Dynegy actually had more throughput (31,788,669 Dth, 33,703,467 Dth, and 29,295,193 Dth respectively) than when the rate differential was lower in years 2009-2011 (24,318,845 Dth, 23,458,829 Dth, and 12,757,304 Dth, respectively).[144] The Commission' s rejection of Dynegy' s and NCGC' s competitiveness claims is amply supported by the record.

Second, Applicants raise the specter of "increasing concentration among suppliers of electricity to wholesale markets."[145] There is simply no evidence in the record in support of this claim. The only citation to the record that Applicants offer in support of this alleged danger is PG&E' s testimony indicating that the capacity factor for Moss Landing Units 1 and 2 could drop significantly under the current rate structure. Even assuming that this is correct, there is no evidence in the record about which generators will take over the market share currently held by Moss Landing Units 1 and 2, or the ownership of those generators. Further, as the Commission notes, "any impacts on *individual* generators would not impair the efficiency of the overall market."[146]

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[143] This figure is taken from Mr. Isemonger' s testimony. See Dynegy-1 (Isemonger) at 15:6-7. However, Calpine' s own review of the rate differential in 2013 indicates that it was actually 29 cents per Dth.

[144] Dynegy-1 (Isemonger) at Table 3. These figures represent a comparison of column B with column C in Mr. Isemonger' s Table 3.

[145] Application at 22, second bullet.

[146] Decision at 332 (emphasis in original).

Third, Applicants cite an alleged increase in greenhouse gas emissions that they argue could be caused by the differential in rates for EG-BB and EG-LT customers.[147] But again, Applicants offer no citation to the record in support of this bare, eleventh-hour assertion.

Fourth, Applicants cite an alleged increase in market prices for electricity when EG-LT units set the market clearing price.[148] But this is not a concern about relative competitiveness of electric generators. As discussed above, the Commission did consider effects of the proposed rates and rate structure on the wider market, and concluded that there would be no meaningful impact.

Finally, Applicants argue that "[r]ate impacts are compounded for those plants that have to run for reliability reasons, creating greater rate shock for those customers relying on the plants to operate even during those times they are not competitive in the market." Again, this argument makes no sense. Under the CAISO tariff, when an electric generator is dispatched for reliability reasons, the CAISO typically reimburses the generator its operating costs.[149] Thus, a generator dispatched for reliability reasons by the CAISO would not be negatively affected by gas transport costs. These higher gas transport costs will be passed through to electric customers, but the Decision finds that these increases are just and reasonable, and necessary to allow for significant improvements in the safety of PG&E' s local transmission pipeline.

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[147] Application at 22-23.
[148] Application at 23, first full bullet.
[149] *See, e.g.*, CAISO Fifth Replacement Electronic Tariff at § 43.7.2 – 43.7.2.1.

Remarkably, in response to the Decision's appropriate consideration of the fact that numerous factors besides gas transmission rates impact the competitiveness of EGs in the market, Applicants assert that "[m]any cost elements contribute to the total cost of electric generation, but only a single cost element is relevant to this proceeding: the cost of PG&E's gas transportation service."[150] This argument is absurd: Dynegy and NCGC have argued throughout the Application—and indeed, throughout this entire proceeding—that the rate increase they will experience will negatively impact their competitive market position and the wholesale electricity market in general. In order to judge the impact of PG&E's rate increases on the wholesale electricity market or individual generators' competitive position within that market, it is absolutely necessary to consider all of the "many cost elements" that "contribute to the total cost of electric generation." Evaluating wholesale electricity markets or the competitiveness of certain electric generators in that market by focusing solely on local gas transmission costs is like evaluating whether a newly designed airplane will fly based solely on an analysis of its landing gear.

The Commission correctly considered this full context. In fact, it is precisely because "[o]ther cost elements are beyond the Commission's ability and jurisdiction to alter"[151] that the Commission correctly concluded it *should not* undertake an attempt to

[150] Application at 24, first bullet.
[151] Application at 24, first bullet.

artificially "level the playing field" by departing from cost causation principles and arbitrarily adjusting one isolated cost.[152]

Perhaps the most incredible claim advanced by Applicants is that "'protection' against competition is not what Dynegy and NCGC have requested."[153] To the contrary, protection from competition is exactly what Dynegy and NCGC have been pursuing throughout this proceeding. NCGC and Dynegy's sole focus in this proceeding has been to reduce the differential between EG-LT and EG-BB rates, precisely in order to protect them from the competitive impacts of accurate, cost-based gas transportation rates on PG&E's system. In fact, in the very next sentence of their Application, Applicants admit that they are focused on "rais[ing] concerns about the tremendous competitive advantage the Decision bestows on their competitors . . . ."[154] The Commission should not offer Dynegy and NCGC the opportunity to re-litigate their requests for subsidies. The Application for Rehearing should be denied.

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[152] See Decision at 333 ("Fairness is not promoted by altering the playing field in one respect to favor one class of competitors through rate design, while those competitors may enjoy other advantages that are not being addressed.")

[153] Application at 23.

[154] Application at 23 – 24.

CONCLUSION

For the reasons explained above, the Commission should deny Dynegy and NCGC' s Application for Rehearing of Decision 16-06-056.

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Respectfully submitted,

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